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July 27, 2009

Brenda Schirmer
Kansas Corporation Commission
1500 SW Arrowhead Road
Topeka, KS 66604-4027

Re: Comments of the Interstate Renewable Energy Council Regarding Interpretation and Implementation of House Bill 2369

Dear Ms. Schirmer:

The Interstate Renewable Energy Council (IREC) appreciates the opportunity to provide comments on the interpretation and implementation of the various provisions of House Bill 2369 which establishes Renewable Energy Standards (RES), net metering and interconnection in Kansas. As discussed below, we believe it is important that the net metering rules and interconnection standards developed pursuant to House Bill 2369 be based on model net metering rules and interconnection standards that reflect best practices. To assist the Commission in these efforts, we discuss IREC's model net metering rules and interconnection standards within the context of House Bill 2369 and the questions posed by Staff via electronic mail on June 30, 2009. We believe the adoption of net metering rules based on best practices will support the overall success of the RES program being established in Kansas by facilitating customer investment in reneweable energy resources. We also suggest that the Kansas Corporation Commission (KCC) adopt uniform interconnection standards based on IREC's model interconnection procedures in order to support net metering and the RES program overall.

I. Introduction

For over two decades, IREC has worked as a non-profit organization to accelerate the sustainable utilization of renewable energy resources and technologies in and through state and local government and community activities. Because solid net metering and interconnection standards form the foundation of successful programs seeking to spur customer investment in renewable energy resources, with funding from the U.S. Department of Energy, IREC's mission includes assisting policymakers in implementing best practices in the areas of net metering and interconnection of renewable resources. To that end, IREC has participated in net metering and interconnection proceedings before over twenty state utility commissions in the past two years.

II. Comments

A. Use of Model Net Metering Rules and Interconnection Standards Ensures These Two Foundational Policies are based on Best Practices Resulting From Utility and Stakeholder Input.

At the onset of any discussion concerning net metering rules and interconnection standards for Kansas, IREC believes it is important to discuss the benefit to Kansas from basing its particular rules on model rules. First, using model rules and standards as a foundation for developing a particular state's policies allows for consistency between utility interconnection standards and net metering rules at both the state and national level. In the context of interconnection, such consistency is important for development of the renewables industry because an investor or developer considering a project in a state must investigate the state's interconnection procedures carefully in order to be sure there are no provisions that might delay or block a proposed project. Installers must similarly review interconnection standards for projects to ensure they know the applicable procedures. When interconnection standards vary widely between utilities within a state or between states, installers and developers face additional, often unnecessary, complexity and uncertainty resulting in additional costs. Similarly, divergent net metering rules result in additional complexity that unnecessarily increases costs. Divergent net metering rules also create confusion among customers seeking to invest in renewable energy resources. These additional cost undermine the economics of renewables and, therefore, inhibit customer investment in renewable generation and growth in the renewables market.

In contrast, consistent, uniform interconnection standards and net metering rules lower costs and thereby promote the development of the renweables market and promote customer investment. Consistency in interconnection standards has the additional benefit of increasing safety by ensuring an increased level of overall familiarity with procedures seen over and over again across utilities by installers. Finally, basing interconnection standards and net metering rules on model procedures developed over time by utility and stakeholder experts conserves scarce resources by leveraging the expertise embodied in the models to everyone's benefit – ratepayers, utilities, industry, and customers seeking to invest in renewable resources.

To meet the need for uniform interconnection standards, IREC has developed *Model Interconnection Standards and Procedures for Small Generator Facilities*.[1] Our model interconnection standards are based on lessons learned from almost 40 states' interconnection programs. IREC's model interconnection standard represents the best practices evolving from negotiations between utility and stakeholder experts on interconnection within state proceedings, the Federal Energy Regulatory Commission (FERC), the National Association of Regulatory Utility Commissioners (NARUC), and the Mid-Atlantic Distributed Resources Initiative (MADRI), and is, therefore, proven to safeguard the electrical grid, utility workers, and other electric ratepayers while permitting renewables to flourish.

[1] IREC's model interconnection standards are available at http://www.irecusa.org/fileadmin/user_upload/ConnectDocs/IC_Model.pdf.

Similarly, IREC developed *Model Net Metering Rules* based on its experiences working with states to implement net metering polices. These model rules are designed to assist policymakers in drafting net metering rules that capture best practices developed across the country.[2]

Of course, best practices continuously evolve as more states adopt interconnection standards and net metering rules and as first mover states revisit their polices in light of experience. To ensure IREC's model interconnection standards and net metering rules continue to encapsulate best practices, IREC embarked on an update to its models in 2009. IREC's latest net metering rules are currently available; we anticipate the updated model interconnection standards to be available in Fall 2009.[3]

Finally, another resource which Staff will undoubtedly find useful in considering what net metering rules and interconnection standards should be put in place for Kansas is *Freeing the Grid* which is published by the Network for New Energy Choices with the assistance of the Vote Solar Initiative and IREC.[4] *Freeing the Grid* discusses the importance of net metering and interconnection in supporting the growth of renewables and provides detailed information on the interconnection standards and net metering rules of all 50 States including providing a letter grade ranking for each state using criteria based on best practices in net metering and interconnection policy.

B. IREC's Net Metering Rules Represent a Solid Set of Net Metering Rules For Use in Kansas.

As noted above, IREC recommends that its model net metering rules form the foundation for development of net metering rules for Kansas. To assist Staff in considering net metering rules that meet the specific requirements of the Net Metering and Easy Connection Act (NMECA), IREC offers the following more detailed discussion.

Definitions

New Sec. 9 of the NMECA contains certain definitions that will need to be incorporated into the definitions contained in Sec. (a) of IREC's model net metering rules. Accordingly, IREC offers the following recommendations:

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[2] IREC's model net metering rules are attached to these comments as Attachment A.

[3] IREC is currently updating its interconnection model to incorporate recent developments in interconnection standards including explicitly allowing third-party ownership, adjusting the Level One cut-off to 25 kW, requiring utilities to provide their interconnection procedures and applications online, improved dispute resolution, allowing a utility to install an external disconnect switch at its own expense, covering all state-jurisdictional interconnections regardless of system size, modifying the network interconnection provisions. The revisions will also tighten terminology, remove alternative agreements, and shorten the total length.

[4] See Network for New Energy Choices, Freeing the Grid (October 2008). A paper copy of *Freeing the Grid* is included with this letter. An electronic copy is available at http://www.newenergychoices.org/uploads/FreeingTheGrid2008_report.pdf.

The definition of "customer-generator" in Sec. (a)(2) of IREC's model net metering rules will need to be modified to reflect New Sec. (9)(b) of NMECA which defines "customer-generator". For simplicity, IREC recommends simple replacement of the model rule's definition of customer-generator with the NMECA's definition so long as the requirements of New Sec. 9(b)(5) are clarified as discussed below.

The definition of "renewable energy generation" contained in Sec. (a)(5) of IREC's model net metering rules and the definition of "biomas" contained in Sec. (a)(1) may need to be modified to reflect the reference in New Sec. 9(b)(1) to "renewable energy resource."[5] Given the flexibility contained in New Sec. 2(f)(11), IREC believes the definitions contained in its model rules can meet the statutory requirements of House Bill 2369 with possibly the removal of reference to "ocean energy" from the definition of "renewable energy generation." The essential element of these two definitions is that they broadly encompass the renewable energy options available to customer-generators seeking to net meter as each customer-generator will have different needs and, therefore, different renewable generation technologies might suit them better than others in fully offsetting their load.

Individual System Capacity

New Sec. 12 of the NMECA requires each utility to offer net metering to residential customers with systems up to 25 kilowatts (kW) and to commercial, industrial, school, local government, state government, federal government, agricultural and institutional customers with systems up to 200 kW. IREC believes the language contained in New Sec. 12 should be seen as specifying a "floor" on the minimum size of generation that must be offered by utilities covered by the NMECA rather than a cap on the size of generation units eligible for net metering. IREC takes this view because the language of New Sec. 12 is focused on what utilities must "allow" rather than focusing on the size of eligible systems and requiring that eligible systems shall be no larger than a certain size.[6] This view is reinforced by the fact that the definition for customer-generator makes reference to "renewable energy resource" in New Sec. 9(b)(1) which is defined by reference to New Sec. 2.[7] New Sec. 2, which defines renewable energy resources generally, contains no size limits with the exception of new hydropower which is capped at 10 MW.[8]

Moreover, IREC considers not imposing an arbitrary cap on individual system capacity to be best practices in this area.[9] IREC's support for eliminating arbitrary individual system capacity stems from the fact that net metering programs are instituted under the premise of allowing utility customers to offset all or part of their load. Language in New Sec 9(b)(4) and New Sec. 12 makes clear that the NMECA is similarly focused.[10]

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[5] "Renewable Energy Resource" is defined by reference in New Sec. 9(d) to New Sec. 2(f) of the Renewable Energy Standards Act which defines "renewable energy resources."
[6] See California Public Utilities Code Sec. 2827(b)(4).
[7] See New Sec. 9(d).
[8] See New Sec. 2(f)(B).
[9] See IREC model net metering rules sec. (b)(1).
[10] New Sec. 9 states in relevant part: (b) " 'Customer-generator' means the owner or operator of a net metered facility which: (4) is intended primarily to offset part or all of the customer-generator's own

A system size limit based on an arbitrary cap cuts short the ability of customers with loads over the cap to offset their load. Moving to a system size cap based on connected load removes this prospect by allowing customers with larger loads, such as universities, military installations or corporate campuses, to participate in the net metering program while also fully offsetting their load as contemplated in the NMECA.[11] It also allows the appropriate size and design of the customer's renewable energy system to be determined by customer load and demand characteristics rather than an arbitrary MW limit.

As discussed above, Sec. 12 of the NMECA can be interpreted in a manner that would allow net metering rules in Kansas to achieve best practices. Accordingly, IREC encourages the KCC to follow IREC's model rule and only cap system size based on a customer's service entrance capacity.[12] This framework allows a customer to fully offset their load by avoiding an arbitrary cap on individual system size. If the KCC believes a numeric cap must be put in place, IREC believes many states offer reasonable options. Many states have moved to a 2 MW cap on eligible system size and IREC supports their move to this relatively large cap. However, it is not the only option available to states that choose to lead in this area. For example, Arizona recently moved to allow net metering systems to be sized up to 125% of a customer's total connected load.[13] New Mexico allows for net metering of systems of up to 80 MW.[14]

Lastly, IREC does not believe any more prescriptive rules or regulations are necessary for determining the size of an individual system a particular customer may install. The modification of "customer-generator" in IREC's model net metering rules to incorporate New Sec. 9(b)(4) will make clear that only systems intended to primarily offset part or all of the customer-generator's load are allowed to participate in the net metering program. Moreover, New Sec. 11(c) requires that annual excess generation credits produced by a customer-generator's system expire at the end of the calendar year. This requirement sends a strong financial signal to customer-generators to size their systems at a level that will offset no more than their annual load.

Total Program Capacity Limit

Total program capacity limits are often premised on concerns for revenue impacts to utilities and are commonly set as a percentage of statewide or utility peak demand. However, this concern fails to recognize that the revenue impacts associated with customer investment in renewable generation are often relatively small for two reasons. First, net-metered systems are sized to offset

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electrical energy requirements." New Sec. 12 states in relevant part: "Customer-generators" shall appropriately size their generation to their expected load.

[11] See Footnote 9 infra.

[12] Service entrance capacity is based on the equipment at the point where electrical service enters a building. This equipment consists of a variety of equipment, including the main junction box, circuit breakers and/or fuses, and meters.

[13] See A.A.C. R14-2-2302(13)(d).

[14] In January 2007, the New Mexico Public Regulation Commission extended the availability of net metering to systems up to 80 megawatts (MW) in capacity. Net metering is available to all "qualifying facilities" (QFs), as defined by the federal Public Utility Regulatory Policies Act of 1978 (PURPA). See NMAC 17.9.570.

customer load. Accordingly, net-metered systems typically export relatively little net generation to the grid. This outcome is specifically reflected in New Sec. 9(b)(4) and New Sec. 12 both of which require customer-generators to size their systems to offset their expected load. Moreover, the requirement that customers size their systems in a manner that primarily offsets all or part of their load is reinforced by the requirement in New Sec. 11(c) that any credits stemming from excess generation not used on a calendar year basis expire. In other words, these credits become a donation to the utility. Second, commercial customers, because of their large loads, often have a harder time fully offsetting their load with on-site generation capacity. Therefore, while the larger renewable systems installed by commercial customers can quickly fill a low program capacity cap, these customers are even less likely to generate more than they consume over the relevant billing period. The upshot is that statewide or utility level program capacity caps, while justified as a means to avoid revenue impacts on utilities, essentially place an artificial cap on the total amount of customers' investment in clean energy resources.

This outcome is counterproductive for two reasons. It potentially ends participation in net metering programs long before customers' desire to invest in clean energy resources has expired. Additionally, because customers do not know when program capacity will be met, their desire to invest in clean energy could be dampened by the potential uncertainty surrounding their ability to participate in net metering. Moreover, because installers do not know when program capacity limits will be met, they have a difficult time planning for future growth in their businesses. By undermining program participation and introducing uncertainty in the marketplace, program capacity limits restrict the growth in the renewables market, which is counter to the rationales animating net metering programs.

Based on these concerns, IREC believes best practice regarding program capacity limits is to set no limit. This outcome avoids the problems identified above and allows renewables markets to grow and thrive based on customer desire to invest in clean renewable energy. New Sec. 10(a) allows the Commission to set a program capacity limit above the 1% specified in the statute. IREC encourages Kansas to join the seventeen states that have achieved best practices by having no program capacity limit for their net metering programs.[15] If the Commission interprets New Sec. 10(a) to require the setting of a numeric limit on program participation, IREC encourages Kansas to join Utah in setting the program capacity limit at 20%.[16]

Rollover

In general, net metering represents a simple and transparent way to value the excess generation a customer brings to the grid. With net metering, customers are able to net generation and consumption over a billing period and receive a credit on their monthly bill during billing periods when their generation is greater than their consumption. The associated excess generation credit can be used to offset billing periods when their consumption is greater than their ability to generate. This straightforward framework is mirrored in New Sec. 11.

An important aspect of the net-metering arrangement is the treatment of monthly excess generation or "rollover". Providing rollover of excess generation is essential to allowing a

[15] See *Freeing the Grid*, pp. 22, 94-95.
[16] See Report and Order Directing Tariff Modifications, issued February 12, 2009, Docket No. 08-035-78.

customer-generator to receive the full benefit of on-site generation during seasons when renewable generation is highest and to use accumulated credits during periods when output is lower. Rollover is particularly important in accommodating customers with electricity requirements that vary seasonally, such as agricultural customers. Furthermore, appropriately valuing the excess generation produced by a customer's renewable generation system sends a strong signal to the consumer that their investment in renewable energy is valued by the state and that they should size their system to meet as much of their on-site load as possible, thereby, decreasing strain on the electric grid. For these reasons, best practice regarding monthly rollover of excess generation is allow a 1:1 kWh rollover of excess generation from month to month.[17] New Sec. 11(b) allows for a 1:1 kWh rollover of monthly excess generation.

Best practice regarding treatment of annual excess generation is to allow for indefinite rollover.[18] Indefinite rollover allows customers maximum flexibility in sizing their system to meet their needs and also avoids perceived unfairness due to arbitrary cutoffs in a customer's ability to rollover excess generation from month to month. For customer-generators who size their systems to offset their annual energy consumption, an annualized period that starts before the peak production period of their generation unit would provide the customer with the most benefit because the excess energy produced during the peak production months would carry forward to the less productive months ahead. However, because intermittency will vary between different customers' systems, it is simply impossible to define an annual period that would benefit all customer-generators equally. Compounding this problem, different generation technologies generally have different peak production months. Unfortunately, Sec. 11(c) requires expiration of net excess generation at the end of each calendar year. Accordingly, IREC proposes the following modification to Sec. (b)(4) of IREC's model net metering rules to reflect this fact:

(4) The Electricity Provider shall carry over any excess kWh credits earned by a Customer-generator and apply those credits to subsequent billing periods to offset the Customer-generator's consumption in those billing periods ~~until all credits are used~~. Any kWh credits remaining at the end of each calendar year shall expire without compensation. Any excess kWh credits shall not reduce any fixed monthly customer charges imposed by the Electricity Provider.

Metering

IREC's model net metering rules Secs. (b)(7)-(10) cover best practices regarding metering of net-metered systems. These rules follow the general belief that customer-generators investing in renewable resources should be treated the same as non-customer-generators and that net metering itself should be simple and straightforward to the customer. Both of these outcomes facilitate customer investment in renewable resources by keeping the process simple and fair. To this end, the model rules specify that the use of a single bi-directional meter is sufficient and that the customer's existing meter may typically be used.[19] New Sec. 10(c) mirrors this

[17] See IREC model net metering rules (b)(3) and (4).
[18] Approximately 11 states allow for indefinite rollover: Indiana, D.C., Colorado, Iowa, Kentucky, Louisiana, Massachusetts, Michigan, Nevada, New Hampshire allow for indefinite rollover, and New York allows indefinite rollover for commercial systems only.
[19] See IREC Model Rule Sec. (b)(8).

understanding by requiring the utility to provide a residential class bidirectional meter to customer-generators at no charge. While New Sec. 10 preserves utility discretion to charge customer-generators for the cost of any additional metering "necessary to accommodate the cutomer-generator's facility", IREC submits that such metering will rarely be necessary and utilities should provide revenue grade meters free of charge to customers whose meters do not meet the requirements of IREC's model net metering rules Sec. (b)(8). Such an outcome is not prohibited by New Sec. 10(c) and would facilitate customer investment in renewable generation as a means of cost-effectively achieving RES requirements.

Ownership of Renewable Energy Credits

Another important issue in addressing the value utility customer investment in renewable generation brings to the grid is recognition that any renewable energy credits (RECs) generated by a customer-generator are not transferred to the utility merely as a result of participation in a net metering program or due to interconnection. The sale of RECs in voluntary or compliance markets potentially provides an important revenue stream for owners of a renewable energy system that directly impacts the potential value of a customer's investment in a renewable energy system. Most importantly, most, if not all, of the RECs generated by a renewable energy system are associated with energy consumed on-site. For these RECs, a utility provides no services to accommodate the on-site energy use and should therefore have no claim to the RECs associated with that generation. While the NMECA does not require the transfer of RECs in order to participate in net metering, IREC believes customer ownership of RECs (absent compensation) should be explicitly addressed within the net metering rules.[20] Eighteen states, including Arkansas and Nebraska, have adopted this best practice and recognized that participation in net metering programs does not require transfer of RECs.[21]

Safeharbor Provisions

Safeharbor provisions protect customers seeking to invest in renewable resources from unspecified fees, standby charges, capacity or other fees not faced by customers who are not customer-generators. Best practice in this area is to explicitly address safeharbor provisions within net metering rules. New Sec. 10(b) of the NMECA offers strong safeharbor language that is reflected in IREC's model net metering rules Sec. (b)(12) and (13).

Disclosure Requirements

IREC encourages utilities to make their net metering rules and interconnection standards available on their website. Providing the net metering rules on the utility website will provide quick and easy access to interested in investing in renewable energy. IREC's model net metering rule Sec. (c)(3) addresses this disclosure method.

[20] See IREC model net metering rules Sec. (b)(11).
[21] See Nebraska and Arkansas Net Metering at *DSIRE-Database of State Incentives for Reneawbles & Efficiency*, available at www.dsireusa.org.

C. IREC's Model Interconnection Standards Offer A Complete Package of Interconnection Standards and Procedures.

IREC's model interconnection standards offer a complete package of interconnection standards and procedures to support investment in renewables by addressing fees, timelines, insurance requirements and indemnification, forms and other important issues. This last point is particularly important because, while New Sec. 13 of the NMECA requires net metered facilities to meet all applicable safety, performance, interconnection and reliability standards established by the national electrical code, the national electrical safety code, the institute for electrical and electronics engineers, underwriters laboratories, the federal energy regulatory commission and any local governing authorities, this statement is not the complete set of interconnection procedures necessary for renewables to flourish. IREC's model interconnection procedures address the requirements of this section while also addressing fees, timelines, and the other issues which all have a direct impact on the cost of installing and interconnecting renewables.[22] Because these other issues directly impact costs, they need to be addressed in a consistent and comprehensive fashion. New Sec. 14 of the NMECA also specifically requires the KCC to establish rules and regulations necessary to administer the act including simple contracts and simple procedures. IREC's model interconnection standard represents a tested package of such procedures.

Finally, the establishment of uniform interconnection procedures for all state-jurisdictional interconnections is critical to ensure interconnection procedures exist for all generating assets seeking to participate in the RES program being established pursuant to the Renewable Energy Standards Act. In conformity with the prevailing standard for interconnection established by IEEE 1547, IREC's model interconnection standards were previously capped at 10 MW. This cap was partially justified by the assumption that facilities larger than 10 MW would be subject to federal jurisdiction rather than state jurisdiction. In practice, states frequently have jurisdiction over the interconnection of qualifying facilities up to 80 MW under the Public Utilities Regulatory Policy Act (PURPA). Accordingly, state interconnection procedures that only cover systems up to 10 MW leave the terms of interconnection for larger facilities subject to negotiation with the utility. Establishing interconnection procedures for these larger facilities would reduce the costs for review of these facilities. IREC's updated interconnection standards will cover all state-jurisdictional interconnections regardless of system size. Both California and North Carolina have adopted this approach in their interconnection standards.

Insurance Requirements

Requirements that a customer-generator procure insurance above what they would normally carry are often based on cost allocation arguments – if something goes wrong with a customer's generation facility and it damages the electrical grid, ratepayers should not have to bear the cost of that damage. Such an argument has intuitive appeal on fairness grounds. However, to IREC's knowledge, with almost 70,000 grid-connected PV systems in the United States, there has never been a documented case of a PV system causing personal injury to utility

[22] See IREC model interconnection standards, sec. (b).

line workers or property damage for a utility.[23] This result should be unsurprising despite the growing number of PV systems in operation as components manufactured and installed in compliance with interconnection standards significantly reduce the risk of potential safety issues.[24] On the other hand, requirements for insurance above what a customer would usually carry increase the cost of a renewable system assuming the particular type of insurance is even available in the marketplace. To the extent insurance requirements are imposed that are prohibitively expensive or unavailable in the marketplace, insurance requirements act effectively to prevent investment in renewable resources.

For these reasons, IREC believes interconnection procedures seeking to achieve best practice regarding insurance should to encourage customers to carry adequate insurance but not require it.[25] This outcome recognizes that it is very unlikely that insurance requirements would provide any benefit to ratepayers, but they would clearly be an extra cost to customers seeking to invest in renewable resources. Many states, such as Arizona, New Mexico, Illinois, New Hampshire, Vermont, West Virginia, Florida and Georgia, have also begun to embrace this view and, therefore, have prohibited additional insurance requirements, do not require additional insurance beyond what a customer would typically carry, or do not mandate it automatically for most renewables as part of their interconnection rules.

IREC appreciates the inclusion of language within New Sec. 13(b) of the NMECA which prohibits requiring customer-generators who meet the requirements of New Sec. 13(a) to purchase additional insurance. This policy choice will allow Kansas to join the growing list of states that prohibit additional insurance for customers meeting their state's interconnection standards.

External Disconnect Switch

The same cost versus benefit concerns discussed above regarding additional insurance requirements hold true when considering interconnection standards related to external disconnect switches. This policy choice must be carefully examined to avoid unnecessarily increasing the costs of renewable energy. Requiring, or allowing a utility to require, installation of an external disconnect switch is often justified from a utility's concern over safety for utility line workers if the grid goes down but a grid-tied system continues to produce power without the utility's knowledge (a situation called "islanding"). If this situation were to occur, a utility line worker could come into contact with an unexpectedly energized line.

However, this safety concern is usually the result of lack of familiarity with UL 1741 certified inverters because all UL 1741 certified inverters meet IEEE standards and, therefore,

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[23] See Sherwood, Larry. (2009) *U.S. Solar Market Trends 2008*. Interstate Renewable Energy Council. Available at: http://www.irecusa.org/fileadmin/user_upload/NationalOutreachDocs/SolarTrendsReports/IREC_Solar_Market_Trends_Report_2008.pdf.

[24] Starrs, Thomas J. (2000) *Barriers and Solutions to Interconnection Issues for Solar Photovoltaic Systems*. Prepared for the Solar Electric Power Association. Available at http://www.resourcesaver.com/file/toolmanager/O63F14189.pdf.

[25] See IREC Model Interconnection Standards, Attachment 5, Section 13.

have automatic shut-off capabilities integrated into their systems.[26] Because of these standards, in the event the grid goes down, all modern inverters stop power flow to the grid automatically.[27] Because of these capabilities, solar systems using a UL 1741 certified inverter would meet the requirements of New Sec. 9(b)(5) as containing a "mechanism" that will automatically disable the generating unit and stop the flow of electricity back to the grid. In fact, a 2008 report by the National Renewable Energy Laboratory (NREL) assessing the need for external disconnect switches concludes that a cost of the switch is made redundant and unnecessary by UL and IEEE standards and the extensive safety training utility workers receive.[28]

The costs of an EDS are not insignificant. In a recent Florida Public Service Commission proceeding on Interconnection and Net Metering of Customer-Owned Renewable Generation,[29] Florida's investor-owned utilities estimated the cost of an EDS to be as high as $1,200 per switch.[30] As a result, an EDS may represent a 6% increase in the cost of installing a $20,000 small PV generator and as PV panel costs come down in price, the cost of a EDS is likely to represent an even larger percentage of the overall cost of installing distributed generation. The Maine Public Utilities Commission reached this conclusion in a report to that state's Legislature, noting that "the cost of the switches relative to the cost of the generation systems will increase over time making the cost of disconnect switches even more likely to discourage further adoption of small generation."[31]

The significant cost of an EDS would be justified if there was a corresponding safety benefit. However, as noted above, modern standards for inverters, utility line worker training, and the absence of any documented safety issues on almost 70,000 gird-connected PV installations provide adequate assurance that prohibiting an external disconnect switch will not compromise the safety of utility workers during a grid outage. Based on the analysis above, IREC believes best practices regarding the external disconnect switch is to prohibit a utility from requiring one for inverter-based systems.[32]

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[26] See Institute of Electrical and Electronics Engineers (IEEE). (2003) *1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.*

[27] See Haynes, Rusty and Whitaker, Church. (2007) *Connecting to the Grid: A Guide To Distributed Generation Interconnection Issues.* Fifth Ed. Interstate Renewable Energy Council (IREC) and North Carolina Solar Center. Available at http://www.irecusa.org/fileadmin/user_upload/ConnectDocs/IC_Guide.pdf.

[28] Coddington, M.H., R.M. Margolis, and J. Aabakken (2008) *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. National Renewable Energy Laboratory. Technical Report: NREL/TP-581-42675. Available at www.nrel.gov/docs/fy08osti/42675.pdf, (2008 NREL Report).

[29] Florida PSC Docket No. 070674-EI.

[30] *Comments of Investor-Owned Utilities*, Docket No. 070674-EI, page 7, ¶ 20 (Jan. 25, 2008). Available at: http://www.psc.state.fl.us/library/filings/08/00653-08/00653-08.pdf.

[31] Maine Public Utilities Commission Inquiry into Interconnection Standards for Small Renewable Energy Facilities, Request for Comment on Report on Statewide Small Generator Interconnection Standards, p. 9, Docket No. 2008-186 (Dec. 5, 2008).

[32] See IREC Model Interconnection Rules Sec. j(5).

As with additional insurance requirements, many states have begun to critically assess the need for an external disconnect switch and have eliminated external disconnect switches on distributed generation meeting certain criteria or left the decision up to individual utilities. For example, Oregon, Florida, and North Carolina recently eliminated any requirement that external disconnect switches be installed at customer expense.[33] New York and New Hampshire are the latest states to join this growing list with New York eliminating the requirement for an EDS for all systems below 25 kW that use a UL 1741 certified inverter.[34] New Hampshire raised the bar in this area further by eliminating the requirement for an EDS for all systems below 100 kW.[35] Pacific Gas and Electric Company (PG&E) and the Sacramento Municipal Utility District (SMUD), two utilities with substantial amounts of interconnected PV systems on their grids, have also voluntarily eliminated requirements for an external disconnect switch from distributed generation meeting certain criteria.[36] Xcel Energy has also recently requested permission to waive the requirement of an external disconnect switch for systems below 10 kW that use a UL 1741 certified inverter.[37]

While New Sec. 13 leaves the requirement of an external disconnect switch to utility discretion, IREC encourages Kansas to lead in this area by implementing best practices and not require an external disconnect switch for inverter-based systems. IREC also requests that the Commission clarify that a UL 1741 certified inverter is among the mechanisms referred to in New Sec. 9(b)(5).

D. Allowing Third-party Ownership of Renewable Energy Systems will Support the Success of the Renewable Energy Standard in Kansas.

Third-party ownership arrangements, such as solar service agreements (SSAs), have become an important component in the creation of a robust solar energy sector. SSAs have become an important component in the creation of a robust solar energy sector because SSAs allow individuals, businesses, governmental entities, schools, religious organizations, and non-profit groups interested in supporting reneweable energy to overcome two frequent barriers to investing in solar energy resources: the lack the necessary capital to invest in such facilities and/or the lack sufficient taxable income to fully capture available federal tax credits and

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[33] See *Order Approving Amended Tariffs and Interconnection Agreements*, Order No. PSC-08-06240TRF-EI at p. 7 (Sep. 24, 2008); *Order Granting Motion for Reconsideration and Amending Generator Interconnection Standard*, NCUC Docket No. E-100, Sub 101 (filed Dec. 16, 2008) (North Carolina grants utilities the discretion to require a EDS for systems under 10 kW, but the utility must pay for its installation).

[34] See Order Modifying Standard Interconnection Requirements, CASE 08-E-1018 (Feb. 13, 2009).

[35] See Final Proposal, Docket No. 08-148, PUC 905.1(a).

[36] See PG&E Press Release. "AC Disconnect Switches for Inverter-Based Generation." Pacific Gas and Electric Co. online. Available at http://www.pge.com/suppliers_purchasing/new_generator/solar_wind_generators/disconnect_switches/; SMUD Press Release. "SMUD Waives Switch Requirement for Solar Systems: Move Makes Solar Installations Easier." Feb. 21, 2007. Available at http://www.smud.org/news/releases/07archive/02_21solar.pdf.

[37] See Application of Public Service Company for Approval of Its 2009 Renewable Energy Standard Compliance Plan, filed in Docket 08A-532E.

incentives for accelerated depreciation of solar equipment available to assist in financing a solar energy system. By combining federal investment tax credits with incentives for accelerated depreciation, the capital cost of a solar energy system can be reduced by up to 60 percent.[38] As a matter of basic economic principles, this reduction in the cost of a solar energy system through the use of an SSA spurs the growth of solar by allowing customers interested in investing in solar energy to do so at significantly less cost.

Recent reports have highlighted the increasing use of third-party ownership arrangements, such as SSAs and their importance in accelerating the rate of adoption and development of solar.[39] According to a recent study by Lawrence Berkeley National Laboratory, SSA agreements have grown from roughly 10% of the non-residential solar market in 2006 to an estimated 90% of the non-residential solar market in 2008.[40] A review of the most recent data from the California Solar Initiative (CSI) includes an estimate that approximately 147 MW of solar has been developed under third-party ownership arrangements.[41] These MWs represent approximately 40% of the capacity of the CSI program.[42] According to the Energy Trust of Oregon, in 2008, more than 80% of the commercial solar installations in Oregon involved third-party ownership arrangements, which represented approximately $35 million of private investment in new clean renewable resources in Oregon.[43]

Given the benefits of SSAs, such growth should not be surprising and IREC believes that it should be encouraged. To that end, IREC's model net metering rules and model interconnection standards do not preclude third-party ownership. Fortunately, the definition of "customer-generator" contained in New Sec. 9(b) is drafted in a manner that does not preclude third-party ownership. New Sec. 9 on its plain terms states that a customer-generator may be either an owner or an operator of a net-metered facility. Accordingly, New Sec. 9(b) appears to contemplate that customer-generators need only exercise some amount of operational control.

IREC is aware of significant use of third-party ownership arrangements in California, New Jersey, Oregon, and Colorado. These states appear to have minimal regulation of third-party ownership agreements and third-party owners are not treated as utilities. IREC is not aware of any state commission maintaining active oversight of the private contracts between third-party owners and host customers. In Oregon, the Public Utilities Commission recently addressed the issue in response to a joint request by PacifiCorp and Honeywell and quickly

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[38] See Solar Energy Industry Association, Guide to Federal Tax Incentives for Solar Energy, Version 1.2, Executive Summary. Available at: www.seia.org/galleries/pdf/SEIA_manual_version_1.2.pdf.

[39] See Bolinger, Mark, "Financing Non-Residential Photovoltaic Projects: Options and Implications." Lawrence Berkeley National Laboratory. January 2009. LBNL-1410E ("Bolinger Report"); Energy Trust of Oregon, Inc., Opening Brief and Waiver of Paper Service of Energy Trust of Oregon, Inc., Docket No. DR 40 (June 30, 2008) (Energy Trust Opening Brief), available at: http://apps.puc.state.or.us/edockets/edocs.asp?FileType=HBC&FileName=dr40hbc143832.pdf; Greentech Media, Inc., "Solar Power Services: How PPAs are Changing the PV Value Chain," (Feb. 14, 2008), available at: http://www.greentechmedia.com/reports/research-report-solar-power-services.html;

[40] Bolinger Report at p. 18.

[41] California Solar Initiative Annual Program Assessment, California Public Utilities Commission, June 2009, p. 32, Available at: http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/103173.PDF.

[42] Id.

[43] See Energy Trust Opening Brief, p. 2.

determined that third-party owners would not be treated as utilities.[44] This decision allowed solar service providers using third-party ownership arrangements to bring the benefits of these arrangements to Oregonians. The California Public Utilities Commission recently reaffirmed its support for third-party ownership arrangements in Decision No. 08-10-036.[45] The Colorado Public Utilities Commission also addressed issues surrounding third-party ownership and public utility status during the development of its renewables portfolio standard program by reconciling their laws order in a manner that allowed third-party ownership to flourish.[46] IREC encourages Kansas to join these states in allowing third-party ownership of renewable energy systems as a means to remove barriers to customer investment in renewable energy resources.

III. Conclusion

IREC appreciates the opportunity to submit these comments to assist Kansas in developing net metering rules and interconnection standards that will support the goals of House Bill 2369. Net metering and interconnection standards based on best practices will ensure that these two foundational elements of a renewables program will support customer investment in renewables and leverage that investment to the benefit of all stakeholders – ratepayers, utilities, customers, and the renewables industry.

If you have any questions, please do not hesitate to contact the undersigned at (510) 597-1798.

Sincerely,

/s/ Joseph F. Wiedman

Joseph F. Wiedman,

Attorney for the Interstate Renewable Energy Council

[44] See Oregon Public Utilities Commission Docket DR 40, Final Order, June 6, 2008, available at: http://apps.puc.state.or.us/orders/2008ords/08-388.pdf.

[45] See Decision No. 08-10-036, *Decision Establishing Multifamily Affordable Solar Housing Program within the California Solar Initiative*, Rulemaking No. 08-03-008 (October 16, 2008), p. 38.

[46] Decision No. C07-0676, Docket No. 06A-478E, Colorado Public Utilities Commission.

Attachment A

IREC Model Net Metering Rules

INTERSTATE RENEWABLE ENERGY COUNCIL

IREC Model Net Metering Rules

http://www.irecusa.org/index.php?id=88

Introduction

IREC first developed its model rules in 2003 in an effort to capture best practices in state net metering policies. Since that time, there has been significant market growth for renewable distributed generation systems, in particular solar photovoltaics. To facilitate this growth, many states have either adopted net metering policies that capture some of the best practices that were identified in the IREC model rules or adopted rules that advance the policies contained in IREC's model. In addition, many of the states that were first adopters of net metering policies have since revisited and updated their policies. While many of the basic issues that are essential to a successful net metering policy have not changed, substantial developments in state net metering policies and the marketplace since 2003 mean an update to IREC's model is necessary to incorporate lessons learned to date and to continue the development and dissemination of best practices.

Among the most exciting state policy changes have been an increase in the size of systems eligible for net metering and expansion of program capacity caps. Several states have also made adjustments that allow customers with multiple meters on contiguous property to allow a single renewable system to offset the aggregate load measured on those meters. Moreover, as the markets for distributed renewable generation have evolved, there have also been some more novel modifications made to state net metering policies. For example, as third-party financing arrangements have become more common, so too have been updates to net metering policies to allow for third-party ownership of net-metered systems. These best practices have been incorporated into this update of IREC's model rules.

On significant points such as size of systems eligible for net metering, program capacity caps, and treatment of annual excess generation, there has been broad variation between states. In an effort to capture this variation, IREC's model rules now include footnotes that discuss the various approaches states have taken on these issues. IREC believes this discussion will be useful to stakeholders to show areas were states have deviated from IREC's best practices.

IREC welcomes the opportunity to work with state utility commissions and individual utilities to develop interconnection procedures; please contact IREC at info@irecusa.org with inquiries. For more information on IREC's model rules and further elaboration of the changes contained in this update, please see www.irecusa.org.

Net Metering

(a) Definitions

(1) "Biomass" means a power source that is comprised of, but not limited to, combustible residues or gases from forest products manufacturing, waste, byproducts, or products from agricultural and orchard crops, waste or co-products from livestock and poultry operations, waste or byproducts from food processing, urban wood waste, municipal liquid waste treatment operations, and landfill gas.[1]

(2) "Customer-generator" means any customer of an Electricity Provider that generates electricity on the customer's side of the billing meter with Renewable Energy Generation that is primarily intended to offset part or all of the customer's electricity requirements. A Customer-generator does not need to be the owner of the Renewable Energy Generation system.

(3) "Electricity Provider" means the jurisdictional entity that is required to offer Net Metering service to eligible Customer-generators.

(4) "Net Metering" means a methodology under which electric energy generated by or on behalf of a Customer-generator and delivered to the Electricity Provider's local distribution facilities may be used to offset electric energy provided by the Electricity Provider to the Customer-generator during the applicable billing period.

(5) "Renewable Energy Generation" means an electrical energy generation system that uses one or more of the following fuels or energy sources: Biomass, solar energy, geothermal energy, wind energy, ocean energy, hydroelectric power, or hydrogen produced from any of these resources.

(6) "Renewable Energy Credit" means a tradable instrument that includes all renewable and environmental attributes associated with the production of electricity from a Renewable Energy Generation system.

(b) Net Metering general provisions

(1) All Electricity Providers shall offer Net Metering to Customer-generators with Renewable Energy Generation that that is interconnected and operated in parallel pursuant to the interconnection rules in Section [[*reference state interconnection rules here*]]; *provided*, *however*, that the rated capacity of the Renewable Energy Generation does not exceed the Customer-generator's service entrance capacity.[2]

[1] The definition of Biomass may need to be adjusted to reflect state renewable portfolio standard definitions.

[2] Some states do not impose limitations on the size of a Renewable Energy Generating system that may be Net Metered. For states that impose system size limitations, such limits vary from as

(2) All Electricity Providers shall make Net Metering available to Customer-generators in a timely manner and on a first-come, first-served basis. An Electricity Provider shall not limit the cumulative, aggregate generating capacity of net-metered systems in any manner.[3]

(3) Each Electricity Provider shall develop a net metering tariff that provides for Customer-generators to be credited in kilowatt-hours (kWh) at a ratio of 1:1 for any excess production of their generating facility that exceeds the Customer-generator's on-site consumption of kWh in the billing period.

(4) The Electricity Provider shall carry over any excess kWh credits earned by a Customer-generator and apply those credits to subsequent billing periods to offset the Customer-generator's consumption in those billing periods until all credits are used.[4] Any excess kWh credits shall not reduce any fixed monthly customer charges imposed by the Electricity Provider.

(5) An Electricity Provider shall offer a Customer-generator the choice of a time-differentiated energy tariff rate or a non-time-differentiated energy tariff rate, if the Electricity Provider offers the choice to customers in the same rate class as the Customer-generator. If a Customer-generator uses a meter and retail billing arrangement that has

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low as 25 kilowatts to as high as 80 megawatts; however, most states appear to be coalescing at a 2-megawatt cap.

[3] Some states cap the total amount of aggregate Renewable Energy Generation that can be Net Metered for a particular Electricity Provider. Most commonly, aggregate enrollment caps are expressed as a percentage of an Electricity Provider's peak demand based on the aggregate of nameplate capacity of the generation systems (though it should be noted that capacity calculations are not standardized in their methodology across or even within states). Such percentages can vary from as low as 0.1% to as high as 20%. IREC believes aggregate caps arbitrarily and unnecessarily limit private investment in Renewable Energy Generation and needlessly curtail the flow of benefits that are associated with customer-side Renewable Energy Generation. Moreover, aggregate caps ignore the fact that many large systems do not export energy yet disproportionately count towards meeting a cap, limiting the number of small systems that are eligible. For these reasons, IREC has not adopted an aggregate enrollment cap in these rules.

[4] States have explored various approaches regarding the treatment of annual net excess generation. The most common approaches allow an Electricity Provider either to retain the net excess generation free of charge or to provide payment for annual net excess generation at the Electricity Provider's avoided cost. However, more novel approaches have also been taken. At least one state directs annual net excess generation to a state low-income assistance program. These rules provide for perpetual rollover of excess generation credits. This approach has been adopted in a number of states and has been adopted as a best practice in these rules. This approach allows for maximum flexibility in sizing a system while assuring a minimum level of regulatory and administrative burden.

time differentiated rates, the Electricity Provider shall net any excess production against on-site consumption within the same time-of-use period in the billing period. Excess monthly kWh credits shall be based on the ratio representing the difference in retail rates for each time of use period.

(6) If a Customer-generator terminates service with the Electricity Provider or switches Electricity Providers, the Electricity Provider is not required to provide compensation to the Customer-generator for any outstanding excess kWh credits.

(7) A Customer-generator facility used for Net Metering shall be equipped with metering equipment that can measure the flow of electricity in both directions. For Customer-generator facilities less than 25 kilowatts (kW) in rated capacity, this shall be accomplished through the use of a single, bi-directional electric revenue meter that has only a single register for billing purposes.[5]

(8) A Customer-generator may choose to use an existing electric revenue meter if the following criteria are met:

i. The meter is capable of measuring the flow of electricity both into and out of the Customer-generator's facility; and

ii. The meter is accurate with a degree of accuracy that the Electricity Provider requires when measuring electricity flowing from the Customer-generator facility to the electric distribution system.

(9) If a Customer-generator's existing electric revenue meter does not meet the requirements of subsection (b)(8), the Electricity Provider shall install and maintain a new revenue meter for the Customer-generator at the Electricity Provider's expense. Any subsequent revenue meter change necessitated by the Customer-generator, whether because of a decision to stop Net Metering or for any other reason, shall be paid for by the Customer-generator.

(10) The Electricity Provider shall not require more than one meter per Customer-generator. However, an additional meter may be installed under either of the following circumstances:

i. The Electricity Provider may install an additional meter at its own expense if the Customer-generator provides written consent; or

ii. The Customer-generator may request that the Electricity Provider install a meter, in addition to the revenue meter addressed in subsection (b)(8), at the Customer-

[5] This provision may need to be modified in states that are implementing advanced metering infrastructure (AMI) and require residential and small commercial customers to have AMI meters; provided, however, that any such meter does not result in an additional cost to a Customer-generator beyond the cost that would be paid in the absence of a customer having Renewable Energy Generation.

generator's expense. In such a case, the Electricity Provider shall charge the Customer-generator no more than the actual cost of the meter and its installation.

(11) A Customer-generator owns the Renewable Energy Credits (RECs) associated with the electricity it generates, unless such RECs were explicitly contracted for through a separate transaction independent of any Net Metering or interconnection tariff or contract.

(12) An Electricity Provider shall provide to Customer-generators electric service at non-discriminatory rates that are identical, with respect to rate structure, retail rate components and any monthly charges, to the rates that a Customer-generator would be charged if not a Customer-generator, including choice of retail tariff schedules.

(13) An Electricity Provider shall not charge a Customer-generator any fee or charge; or require additional equipment, insurance or any other requirement not specifically authorized under this sub-section or the interconnection rules in Section [[*reference state interconnection rules here*]], unless the fee, charge or other requirement would apply to other similarly situated customers who are not Customer-generators.

(14) Each Electricity Provider shall submit an annual Net Metering report to the [[*insert name of state regulatory commission*]]. The report shall be submitted by [[*insert date*]] of each year, and shall include the following information for the previous year:

i. The total number of Net Metered Customer-generator facilities, by resource type;

ii. The total rated generating capacity of Net Metered Customer-generator facilities, by resource type;

iii. The total number of kWh received from Net Metered Customer-generators; and

iv. The total estimated amount of kWh produced by Net Metered Customer-generators, provided that this estimate does not require additional metering equipment.

(c) General Provisions

(1) If a Customer-generator's Renewable Energy Generation system has been approved for interconnection under the interconnection rules in Section [[*reference state interconnection rules here*]], the Electricity Provider shall not require a Customer-generator to test or perform maintenance on the Customer-generator's system except in the case of any testing or maintenance recommended by the system manufacturer.

(2) An Electricity Provider shall have the right to inspect a Customer-generator's system during reasonable hours and with reasonable prior notice to the Customer-generator. If an Electricity Provider finds that the Customer-generator's system is not in compliance with the requirements of the interconnection rules in Section [[*reference state interconnection rules here*]] and the requirements of IEEE Standard 1547, and non-compliance adversely affects the safety or reliability of the Electricity Provider's facilities or of other

customers' facilities, the Electricity Provider may require the Customer-generator to disconnect the facility until compliance is achieved.

(3) Each Electricity Provider shall make Net Metering applications available through the Electricity Provider's website.[6]

(d) Meter aggregation

(1) For Customer-generators participating in meter aggregation, the following provisions apply:

i. For the purpose of measuring electricity usage under these Net Metering rules, an Electricity Provider must, upon request from a Customer-generator, aggregate for billing purposes a meter to which the Net Metering facility is physically attached ("designated meter") with one or more meters ("additional meter") in the manner set out in this subsection. This rule is mandatory upon the Electricity Provider only when:

a. The additional meter is located on the Customer-generator's contiguous property;

b. The additional meter is used to measure only electricity used for the Customer-generator's requirements;

ii. A Customer-generator must give at least 30 days notice to the Electricity Provider to request that additional meters be included in meter aggregation. The specific meters must be identified at the time of such request. In the event that more than one additional meter is identified, the Customer-generator must designate the rank order for the additional meters to which Net Metering credits are to be applied.

iii. The Net Metering credits will apply only to charges that use kWh as the billing determinant. All other charges applicable to each meter account will be billed to the Customer-generator.

iv. If in a monthly billing period, the Net Metering facility supplies more electricity to the Electricity Provider than the energy usage recorded by the Customer-generator's designated meter, the Electricity Provider will apply credits to additional meters in the rank order provided by the Customer-generator, and any remaining credits after doing so will be rolled over to the designated meter for use during the subsequent billing period.

v. Customer-generators participating in meter aggregation do not have to have all meters on the same rate schedule.

[6] In states or jurisdictions where wet signatures are not required, Electricity Providers shall accept applications online.